Attachment 1: EPA Comments

Section 1: Site Characterization

The characterization of geologic and hydrogeologic parameters should be based on site-specific data such as geologic cores, outcrop data, seismic surveys, and well logs. Please provide EPA with more site-specific data and updated geologic and hydrogeologic parameters that reflect that data.

Section 2: Plume Model

HCS Statement

While the following discussion specifically focuses on Ex. 9 Wells, all three (3) wells were modeled simultaneously in order to consider the relationship between the wells during injection operations. It was necessary to ensure that the three (3) plumes did not significantly impact or affect each other within the disposal reservoir.

EPA Comment

The map on page 5 of the Introduction, Section 0 (Figure Intro-1) shows overlap occurring for well plumes 1 and 3 and contact occurring for plumes 1 and 2. Explain how this overlap and contact is not significant interaction since the figure does not depict plumes in different model layers. Provide EPA with a revised map that says what model layers these three plumes are in and the model times they represent.

Model Inputs

HCS Statement, P. 2-1

Residual gas trapping is the physical trapping of CO2 within pore space. As water is displaced in the rock, the CO2 fills in the space. However, depending on the movement of CO2 and the aqueous phase through saturation and capillary forces, CO2 will remain imbibed within the pore space and become trapped.

EPA Comment

Explain when and where displacement of CO2 by the original wetting fluid/brine occurs, the rate of simulated displacement and how that will be checked and measured in the subsurface, and how far outward from the injection well imbibition is projected to occur after injection ceases.

Stratigraphy of Location

HCS Statement, p. 2-3

The model was built using the geologic data described in Section 1 – Site Characterization which describes how the analysis of well logs, core data, and seismic data were used to generate structure maps, hydrogeology, and define other rock properties.

EPA Comment

Besides the model properties provided in Section 2, what are the "other rock properties" mentioned above?

Hydrogeology, p 2.4 -2.5

HCS Statement

A summary table of the values for porosity and permeability used in the model is shown below (referring to table 2-1). Using the same core data, vertical permeability in the sand was shown to be 91% of the horizontal permeability. This relationship is applied throughout the model.

EPA Comment

Provide why the relationship of vertical permeability is 91% to horizontal permeability and why that is appropriate throughout the entire model. Since there is no site-specific core data, explain why using the relationship throughout the model is appropriate when sedimentation patterns and stratigraphic relationships resulting from deltaic environments of deposition and marine sedimentation patterns are complex and change over short distances. In addition, if regional or local geologic studies were used for the 91% estimate, provide information from such studies that explicitly describes the depositional characteristics and patterns of the lower Miocene that support the estimate for the entire model.

Explain why the average values for permeability (Table 2-1) are used throughout the entire model instead of assigning permeability values for each layer (Figure 2-1).

Relative Permeability and Capillary Pressure, p. 2-5

HCS Statement

Relative permeability relationships between water and carbon dioxide were determined for the sand in the core sample taken at 7,622.5 feet. The residual water saturation was found to be 49.1% at the end of the drainage phase. The Ex. 9 Wells permeability was found to be 1,040 mD and the maximum effective permeability of CO_2 was found to be 84.4 mD. In the model, the relative permeability relationships found for the sand are applied across the entire model.

EPA Comment

Justify applying the relative permeability relationships found for the sand across the entire model. Since there is no site-specific core data, explain why using the relative permeability relationship throughout the model is appropriate when sediment particle sizes, sorting and packing, and sedimentation patterns and stratigraphic relationships from deltaic environments of deposition and marine sedimentation patterns are complex and change over short distances. In addition, provide any related information from regional or local geologic studies, if used for Section 2, that support the assumption of applying the relative permeability relationships found for the sand across the entire model.

HCS Statement, P. 2.6

A study was presented at the SPE Annual Technical Conference and Exhibition in October 2003 that focused on correlations used to determine maximum residual gas saturation in various sandstone reservoirs. From this study, it was found that for sandstone with large porosity, and specifically sandstone with large pore sizes, had the ability to trap more residual gas (Suzanne et al., 2003). Using the results of the study, the maximum residual gas saturation was determined to be 40%. The following chart shows the distribution of pore sizes found in the sand from the core analysis:

EPA Comment

Clarify which study is being referred to for determining the maximum residual gas saturation to be 40%; (i.e., Suzanne et al., 2003, or from project core analysis). In addition, provide the complete reference for Suzanne et al., 2003.

HCS Statement p. 2-7

Capillary pressure data tests were performed by mercury injection into the core samples. This was done for the upper confining shale, the lower confining shale, and sand at 7,627.5 feet. In the model, the capillary pressure results of the sand were applied to all the sand layers and the capillary pressure results of the upper confining shale were applied to all the shale layers.

EPA Comment

Explain why applying the capillary pressure result from a single sand sample and the capillary pressure result from a single shale sample is appropriate for all sand and shale layers in the model. Since there is no site-specific core data, provide a justification based on the known environments of deposition, sedimentation patterns, and stratigraphic relationships from regional and local geologic studies that explain why the same capillary pressure can be applied for the entire vertical distance. It does not appear reasonable to EPA to assume that 63' of core, from cores 3 and/or 4, which represents approximately 1.1% of the entire vertical injection interval, can represent all lower Miocene sand layers over an approximately 5607' vertical distance.

Initial Conditions

HCS Statement, p 2-8

From core data, we found the reservoir to consist of over 92% water, with less than 2% oil.

EPA Comment

Explain which well(s) this core came from Ex. 9 Wells the offset well, or other wells. Explain how many core samples were used and whether 92% water with less than 2% oil values was used as initial conditions for all model layers. If 92% water with less than 2% was used for all model layers, justify doing so and include supporting information based on any regional or local geologic studies since there is no site-specific core data.

Injected Composition

HCS Statement, p. 2-9

While there will be 16 different components in the actual injected stream of the project, the majority of those components make up only a small fraction of the total stream and would significantly increase the computational demand of the model if they were all included. In the model, the injected composition is approximately 98% carbon dioxide and 2% methane. This gives a molecular weight of 42.38 lb/lb-mol compared to an expected 42.91 lb/lb-mol if all 16 components were included.

EPA Comment

Although CO_2 and methane make up nearly all the injected composition at a given time, the percentage of the remaining components should be considered for modeling because the total volume of these components resulting from injection over time may be significant. Given the possible significant totals over time, explain why approximately 2% of contaminants should not be modeled besides concerns about computational demand. Further, clarify if the model can simulate the effects of components with relatively high densities (such as n-Nonane, n-Heptane, and n-Octane) filling pore spaces over time and any impact they may have on CO_2 plume movement.

Completion Plan

HCS Statement, p. 2-11 and p. 2-12

The model is simulated for a total of 120 years consisting of 20 years of active injection and an additional 100 years of density drift to allow time for the plume to fully develop.

EPA Comment

It is not clear from the provided information that the plume movement ceased after 120 years. Since 120 years has not been determined to be the fixed time period specified by the UIC Program Director, the model must be revised to determine the area of review based on the requirements in 40 CFR 146.84(c)(1).

EPA Comment

Discuss what all model inputs will need to be changed if logging at the injection well sites finds that the sand unit/injection zone elevations are different from the current model's elevations.

Model Orientation and Gridding Parameters

Spatial Conditions, p. 2-14

HCS Statement

There were 34 distinct sand packages identified as targets for injection using gamma/resistivity logs from the Ex. 9 Wells type well.

EPA Comment

Explain the difference between Ex. 9 Wells) and API No. Ex. 9 Wells type well. Are these the same wells? If not, show on a map where API No. Ex. 9 Wells is located and provide core and lithologic information for this well.

HCS Statement

This results in a total of 85 layers in the model, comprised of 52 sand layers and 33 shale layers. As discussed in the Completion Strategy section above, the 52 sands were subdivided into 13 different perforation intervals. These 15 intervals comprise a single model run with staged injection durations.

EPA Comment

Clarify if there are 13 or 15 different perforation intervals.

HCS Statement

The thickness of each layer within the model is based on the thicknesses seen in the type well of Ex. 9 Wells

EPA Comment

Same comment as above. Explain the difference between Ex. 9 Wells Ex. 9 Wells and Ex. 9 Wells type well. Are these the same wells? If not, show on a map where Ex. 9 Wells is located and provide core and lithologic information for this well.

HCS Statement, p. 2-15

Completion intervals were modeled using appropriate contours for the depth of the sand. These contours allowed for a more accurate simulation of plume behavior taking into account structural dip, subsurface features such as pinchouts to the Southeast, and any overlaps identified during the interpretation of the 3D seismic survey information.

EPA Comment

Provide the contour maps mentioned in the above statement.

Boundary Conditions

HCS Comment, 2-15

The boundary conditions of the model are set up to assume an infinitely acting reservoir. This was done by multiplying the volume of the outermost grid blocks in each layer by 10,000. Both the overlying and underlying confining shales are assumed to be impermeable.

EPA Statement

Show an aerial view of the entire model domain, including active and inactive cells on the map provided on page 5 of the Project Overview (Figure Into-1) or similar maps. Show the locations of the exterior model boundary conditions. Show locations of any boundary conditions inside the model domain. Explain any assumptions related to the presence of the salt dome and any influences it may have on model boundaries.

Model Time Frame

HCS Statement, p. 2-15

The model is simulated for a total of 120 years consisting of 20 years of active injection and an additional 100 years of density drift to allow time for the plume to fully develop. However, after initial runs of the model, it was determined that the plume reaches its maximum size only two (2) years after injection ceases. Furthermore, within ten years nearly all of the supercritical carbon dioxide is trapped in place, meaning that no material change in plume is seen after such time.

EPA Comment

As stated on p. 2-16, the maximum extent of the plume is considered the point where the concentration of supercritical phase CO2 reaches below 3% saturation. Provide maps and cross-sections similar to figures 2-8, 2-11, and 2-12, showing the extent of plumes for the concentration of supercritical phase CO2 at 2%, 1%, and 0% saturation.

Model Results

HCS Statement, P. 2-15

The primary objective of the model is to optimize injection patterns to reduce the horizontal extent of the plume while keeping below the fracture pressure for the targeted injection rate.

EPA Comment

Provide a more detailed explanation about what HCS refers to as an injection pattern (e.g., does this refer to the length of injection events, injection timing between wells 1, 2, and 3, or other simulations. Explain how optimizing was performed, including whether it was achieved using automated or manual techniques. Further, explain how the model sensitivity was evaluated with respect to optimization.

HCS Statement, p. 2-16

Due to the large number of total plumes (one for each sand layer), this discussion focuses on the layers that had the greatest impact on the maximum aerial extent of the plume. The results of each sand layer can be found in Appendix D – Plume Model. The maximum extent of the plume is considered to be the point where the concentration of supercritical phase CO2 reaches below 3% saturation.

EPA Comment

EPA does not specify that the maximum extent of a plume is where the concentration of supercritical phase CO2 reaches below 3% saturation, and HCS does not explain why 3% was chosen. HCS must revise the model to determine the area of review based on the requirements in 40 CFR 146.84(c)(1).

HCS Statement

This is due to the carbon dioxide becoming trapped from hysteresis effects and the CO2 beginning to dissolve in the brine.

EPA Comment

Explain how GEM simulates carbon dioxide becoming trapped from hysteresis and how GEM simulates CO2 dissolving in brine. Provide the model inputs required by GEM for these computations.

Provide model output showing the effect of imbibition over time from the injection wells outward after injection is stopped.

Section 3: AOR

The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and displaced fluids and is based on available site characterization, monitoring, and operational data as outlined in [HYPERLINK "https://www.ecfr.gov/current/title-40/section-146.84"]

The model must:
(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s), and any additional zones; and anticipated operating data, including

injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;
(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions

Please provide EPA with detailed geologic data such as cores, outcrop data, seismic surveys, and well logs that will be used for more detailed site characterization and AOR delineation.